Decision 17-09-035 September 28, 2017

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Revise its Electric Marginal Costs, Revenue Allocation and Rate Design. (U39M)	Application 16-06-013 (Filed June 30, 2016)

DECISION IDENTIFYING FIXED COST CATEGORIES TO BE INCLUDED IN A FIXED CHARGE

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DECISION IDENTIFYING FIXED COST CATEGORIES TO BE INCLUDED IN A FIXED CHARGE

Summary

This decision identifies categories of fixed costs that could be included in the calculation of a fixed charge, in the event a fixed charge proposal is brought before the Commission for approval in future applications.

Specifically, we determine that a fixed charge should include only revenue cycle services costs (costs for account set-up, metering services, billing and payment) with certain exclusions, all meter capital costs, and minimum service drop and final line transformer costs calculated by using the minimum observed cost for the residential class. For the purpose of this decision, fixed charges cannot cover any costs that vary with demand and must exclude generation charges, transmission charges and all non-bypassable charges such as public purpose program charges. We also determine that the equal percentage of marginal cost scalar will not be applied when calculating fixed costs for purposes of setting a fixed charge. The Commission may revisit these exclusions in the future.

This proceeding remains open.

1. Procedural History

Assembly Bill (AB) 327 codified as Public Utilities Code § 739.9(e) gave the California Public Utilities Commission (Commission) the authority to approve "new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electric service to residential customers,"[1] but it did not require the Commission to approve any new or expanded fixed

[1] Public Utilities Code § 739.9(e).

charge.[2] The statute capped the fixed charges at $10 per month for residential customers not enrolled in the California Alternate Rates for Energy (CARE) program and at $5 per month for customers enrolled in the CARE program. The maximum allowable fixed charge can be adjusted by no more than the annual percentage increase in the Consumer Price Index for the prior calendar year.[3]

In Rulemaking (R.) 12-06-013, the Commission's current residential electric rate design examination, Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) each proposed that a fixed monthly charge be implemented for residential electric rates. They contended that "fixed charges would better link cost recovery to cost causation, reduce cross subsidies, and ensure some degree of cost recovery from all customers."[4] Each utility proposed a monthly service fee of $5 and $2.50 for its non-CARE and CARE rates beginning in 2015, increasing to $10 and $5, respectively, for non-CARE and CARE by 2017.[5]

Decision (D.) 15-07-001 found that, "No party in this proceeding denies that utilities have fixed costs, or the existence of customer-related fixed costs. Instead, the debate centers on how the utilities should recover these fixed costs."[6] The Commission did not adopt new or increased fixed charges in D.15-07-001, but instead established a process designed to ensure that any fixed charge that may be adopted in the future: (1) reflects appropriate costs; (2) is calculated

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[2] Public Utilities Code § 739.9(g).

[3] Public Utilities Code § 739.9(f).

[4] D.15-07-001 at 189.

[5] D.15-07-001 at 199.

[6] D.15-07-001 at 189.

using a consistent methodology across utilities; and (3) would be implemented after each utility has shifted to default time-of-use (TOU) rates.[7] D.15-07-001 also ordered that a workshop be held to discuss residential fixed charges in a General Rate Case (GRC) Phase 2 proceeding of either PG&E, SCE or SDG&E.

The November 5, 2015 Administrative Law Judge (ALJ) Ruling issued in Application (A.) 15-04-012 and A.14-06-014 directed that PG&E's GRC Phase 2 proceeding include within its scope a workshop process to consider and develop a record to support a Commission decision adopting categories of fixed costs in compliance with D.15-07-001. The workshop issues were to include:

a. Which fixed costs are appropriate to collect through a fixed charge?

b. Ensuring that any fixed charge amount treats small and large customers fairly;

c. Timing of including new or increased fixed charges in residential rates; and

d. Marketing, education and outreach for fixed charges.

D.15-07-001 also stated that "the decision on the proposed fixed charge calculation will apply to the specific utility, with respect to the actual amount of fixed costs identified, but the determination of which categories of costs the Commission determines should be permitted in a fixed charge should be considered precedential. The GRC Phase 2 applications for the other two IOUs [investor-owned utilities] should rely on the findings from the first decision. Any requested variations from the methodology approved for the first IOU shall

[7] D.15-07-001 at 190.

be accompanied by material evidence demonstrating differences between the two IOUs' systems."[8]

PG&E filed this proceeding, A.16-06-013, to revise its electric marginal costs, revenue allocation, and rate design, including a Fixed Cost Report on the issues identified in D.15-07-001.[9] The Utility Reform Network (TURN) and the Solar Energy Industries Association (SEIA) criticized PG&E's Fixed Cost Report in protests on August 9, 2016, and August 15, 2016, respectively.

PG&E, the Office of Ratepayer Advocates (ORA), SEIA, California Independent Petroleum Association, and Western Manufactured Housing Communities Association filed prehearing conference statements on September 9, 2016. On September 12, 2016, a prehearing conference was held to determine parties, discuss the scope, the schedule, and other procedural matters in A.16-06-013.

As directed in a September 22, 2016 Ruling, SDG&E and SCE submitted fixed cost reports on October 6, 2016. The reports addressed categories of fixed costs to be considered in developing a future fixed charge. An alternative proposal (Alternative Proposal) by ORA, SEIA, and TURN (Joint Parties) for determination of fixed costs was filed on October 26, 2016. A survey study on fixed charges conducted by the Brattle Group for PG&E was filed on the same date.

Workshops on the topic of fixed charges were held on October 13, 2016, and on November 2, 2016. A prehearing conference (PHC) was held on

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8 D.15-07-001 at 192 and 193.

9 PG&E updated and served its Fixed Cost Report on December 20, 2016.

November 2, 2016, prior to the second workshop, to discuss the relationship of the Fixed Charge Track to the GRC Phase 2 and other matters.

A November 21, 2016 ALJ Ruling clarified that the Energy Division Adjusted Rental Method for Marginal Customer Cost presentation given in the November 2, 2016 workshop was included in the administrative record and could be addressed in comments. The same ruling confirmed that any decision in the Fixed Charge Track was limited to rate design for the residential class and the materials used in this track could not be relied on as evidence in the GRC Phase 2 portion of the proceeding. It also directed parties to respond to a set of questions on fixed charges. Opening comments and responses to questions listed in Appendix A to the November 21, 2016 ALJ Ruling, were provided on January 20, 2017 by SCE, PG&E, and SDG&E (Joint Utilities), Joint Parties, Center for Accessible Technology, Consumer Federation of California (CFC), and Sierra Club. Reply comments were filed on February 24, 2017 by Joint Parties, Joint Utilities, Sierra Club, and Consumer Federation of California.

On September 22, 2017, by e-mail to the assigned ALJs, CFC requested an opportunity to comment on the revised proposed decision. CFC's informal request is denied.

2. Issues before the Commission

Pursuant to D.15-07-001 and confirmed in the October 19, 2016 Scoping Memo, there are four issues we consider in this decision:

1. What fixed costs are appropriate for recovery through a residential fixed charge?
2. What additional steps should be taken to ensure that any residential fixed charge treats small and large customers fairly?

3. What is the proper timing of potential new or increased fixed charges in residential rates?
4. What additional marketing, education, and outreach plans are necessary and appropriate for fixed charges?

3. Which Fixed Cost Categories Are Appropriate for Recovery Through a Residential Fixed Charge?

As a preliminary matter, it is important to distinguish between fixed costs and a fixed charge. Public Utilities Code § 739.9(a) defines fixed charge as "any fixed customer charge, basic service fee, demand differentiated basic service fee, demand charge, or other charge not based upon the volume of electricity consumed." While this generic definition enumerates what charges must be considered a fixed charge (and therefore subject to the restrictions of Public Utilities Code § 739.9(a)), it does not require the Commission to adopt a fixed charge, nor does it specify what constitutes a fixed cost. If the Commission adopts new, or expands existing, fixed charges, Public Utilities Code § 739.9(e) requires that any approved charges (1) "Reasonably reflect an appropriate portion of the different cost of serving small and large customers" (2) "Not unreasonably impair incentives for conservation and energy efficiency" and (3) "Not overburden low-income customers." A fixed charge may appear on customers' bills, as a means to collect all, or a portion, of fixed costs. For residential customers, PG&E, SCE and SDG&E currently collect the vast majority of their costs through variable energy charges.

In contrast to fixed charges, fixed costs are not defined in statute and the notion of fixed costs is highly contentious. The Joint Utilities interpret fixed costs as all marginal customer costs, such as account set up, meter reading, billing and payment, metering services, (revenue cycle services cost, collectively) and new connections costs, and all other non-marginal costs that do not vary with the number of customers and usage in kilowatt hours.[10] The Joint Utilities also include marginal capacity costs and non-bypassable charges under their rubric of fixed costs.[11] A central tenet to the Joint Utilities proposal is that a portion of the distribution system, such as final line transformer and wires connecting the final line transformer to the customer meter, is related to providing access to the grid, as opposed to serving customer demand, and that this 'minimum system' supports a significant share of distribution costs being categorized as fixed costs. The Joint Utilities maintain that their goal with this definition of fixed costs is to better reflect cost of service, send more accurate cost-based price signals to customers, and mitigate the current inequities in residential electric rates, which the Joint Utilities attribute to higher usage customers bearing a disproportionately high share of the fixed costs compared to lower usage customers.[12]

In contrast, the Joint Parties take a more narrow approach and propose that only ongoing (non-capital related) marginal customer costs that do not vary with customer usage should be included in a fixed charge. They limit these costs to customer service costs, such as meter reading, billing and payment, metering services, and operations and maintenance (O&M) costs for the final-line transformer, service line, and meter (TSM) equipment.[13] Although the Joint Parties view new fixed charges as being neither necessary nor reasonable, instead preferring a minimum bill approach, they support excluding all costs

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10 Joint Utilities Opening Comments at 5 and 6.

11 Joint Utilities Opening Comments at 30 and 31.

12 Joint Utilities Opening Comments at 2 and 3.

13 Joint Parties Alternative Proposal at 11 and 12.

that they consider sunk such as TSM equipment costs, as well as costs that vary with demand, usage, generation, or are related to public purpose programs.[14] The Joint Parties also argue that any adopted method should reflect the Commission's Rate Design Principles, adopted in D.15-07-001.[15]

D.15-07-001 approved a residential minimum bill in lieu of a fixed charge, finding that the investor-owned utilities failed to articulate a clear and consistent methodology for calculating a fixed charge. The Joint Parties express their support for continuing to use a minimum bill approach throughout the proceeding. They prefer the current minimum bill implementation due to the debate over the portion of distribution costs that are customer versus demand-related; characterization of hookup costs; and lack of customer charges in competitive markets.[16] Center for Accessible Technology supports a minimum bill approach as well.

Although AB 327, codified as Public Utilities Code § 739.9(h), gives the Commission authority to consider the use of minimum bills in lieu of a fixed charge, making a determination on the use of a minimum bill or a method to calculate a minimum bill is outside the scope of this proceeding.

The Joint Utilities' and the Joint Parties' fixed charge proposals generate very different results in dollar amounts, as illustrated in individual utility proposals and the Joint Parties Alternative Proposal. The two proposals adopt different definitions of fixed cost as a starting point; consequently, the two proposals (1) widely vary in terms of the cost categories they include in the

14 Joint Parties Opening Comments at 2.

15 Joint Parties Alternative Proposal at 2.

16 Joint Parties Alternative Proposal at 8 and 9.

calculation of a fixed charge; (2) vary in their selection of method to compute customer connection costs, which is a subcategory of marginal customer costs; and (3) take different views on scaling, *i.e.*, using equal percentage of marginal cost factor to close the gap between the revenue requirement and marginal cost revenues.

The difference between the illustrative fixed charges calculated by these approaches is significant: the Joint Utilities initial approach, as described in pre January 20, 2017 filings, produces fixed charges in the range of $35-$81 per month per customer, depending on the utility,[17] whereas the Joint Parties proposal yields fixed charges in the range of $2.27-$4.70 per month per customer. Because the numbers calculated by the Joint Utilities proposed method go beyond the dollar amount authorized by the statute, they are bound to be capped for each utility by the $10 limit for non-CARE customers and $5 limit for CARE customers.

We consider the components of these proposals in more detail below.

3.1. Fixed Cost Definition

Lack of a clear and consistent methodology across the utilities to identify and calculate fixed costs was a major factor that led the Commission to examine the fixed charge issue in more depth in this proceeding. As stated in D.15-07-001, the utilities argued for a fairly broad interpretation of fixed costs while other parties supported a more narrow definition in R.12-06-013.[18] Several parties,

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[17] In comments filed on January 20, 2017 and beyond, PG&E and SCE included additional costs which would increase fixed charges beyond the levels they initially proposed.

[18] D.15-07-001 at 197.

including both utilities and non-utility parties, offered different methodologies for determining the fixed costs that could be used as a basis for a fixed charge. Even though the disagreement on the definition and interpretation of fixed costs continued in this proceeding, parties generally coalesced around two different definitions of fixed costs and methodologies to calculate fixed charges, and presented clear and comprehensible approaches.

Specifically, the Joint Utilities define fixed costs as encompassing all marginal customer and capacity costs plus all other non-marginal costs incurred to serve customers.[19] In other words, the Joint Utilities consider all costs of providing electric service that are allocated to residential customers, except marginal energy costs, to be fixed costs. In contrast, the Joint Parties define fixed costs as ongoing marginal customer costs that do not vary with customer usage.[20]

The Joint Utilities consider "usage" to be energy-related (kWh), only. For example, the Joint Utilities argue that distribution capacity costs are incurred independently of the actual volume of electricity consumed, and should be included as fixed costs. In contrast, Joint Parties argue that "usage" cannot be attributed to kWh usage only, because a customer can use the system or circuit capacity even if the customer does not use energy; they contend that capacity costs vary with individual customer demand on the system, and therefore should not be considered fixed costs.

Defining what a fixed cost means will provide us with a framework to determine the appropriate categories of fixed cost for inclusion in a fixed charge.

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[19] Joint Utilities Opening Comments at 5 and 6.

[20] Joint Parties Alternative Proposal at 3.

In D.15-07-001, the Commission defined fixed costs as those that do not vary as a result of individual customer usage, without being definitive on the term "usage,"[21] and also found that "fixed costs should be calculated in a manner that truly reflects customer-specific costs, and minimizes regressive impacts of this cost collection method."[22]

A fundamental dispute in this proceeding is what is meant by the term 'usage,' and whether there are system-related fixed costs that the utilities incur to provide customer access to the system, independent of a customer's usage in kW or kWh. On this issue we find some merit to the Joint Utilities argument in favor of including an expanded definition of distribution fixed costs; for example, power poles in residential neighborhoods do not vary with a customer's demand or usage, but are necessary for the utility to provide basic service. Such costs are captured by the Joint Utilities proposal to use an equal percentage of marginal cost (EPMC) factor as discussed below. Further, as the electricity market continues to evolve to accommodate new opportunities for how customers procure and conserve electricity to meet their needs, we are cognizant of the importance of having a mechanism for collecting these fixed distribution costs. However, poles and other "upstream" distribution costs do not fall within our definition of fixed costs adopted in this decision, because they are not customer-specific.

With that said, a second fundamental issue identified in D.15-07-001 is that any fixed cost included in a fixed charge should be calculated in a way that truly reflects customer-specific costs, defined here as costs of those distribution

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21 D.15-07-001 at 190.

22 D.15-07-001 at 191.

facilities that can be identified with the specific customer or small group of adjacent customers those distribution facilities serve. Such costs can be assigned to individual customers and reasonably reflect the level of costs that they impose on the system, by virtue of being connected to the distribution grid. Historically, the Commission has separated distribution costs into two categories: customer-related and demand-related. Specifically, the meter, service drop, and final line transformer were considered as customer-related grid access facilities; all other distribution facilities were considered demand-related.[23]

The record here shows a need for further-refinement: As demonstrated by the Joint Parties, some grid access facilities are in part demand-related; and as demonstrated by the Joint Utilities (through statistical analysis), some portions of upstream distribution costs are arguably customer-related. However, in order to adhere to cost causation principles and to address equity concerns, it is not enough for fixed costs to be customer-related; they must also be customer-specific (*i.e.,* facilities that serve only one customer or a small group of adjacent customers). Limiting fixed charges to the recovery of fixed costs as defined thus minimizes the regressive impacts of this collection method.[24]

This idea is also contained in Public Utilities Code § 739.9(e)(1), which directs the Commission to ensure that any approved fixed charges "reasonably reflect an appropriate portion of the different costs serving small and large customers." As we will discuss in Section 4, there are many ways in which demand-related costs may be differentiated, including based on customer size, residence type, or single-family versus multi-family; however, none of the

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23 *See*, D.86-08-083 and D.88-12-085.

24 D.15-07-001 at 190 and 191.

approaches considered in this proceeding to make that differentiation provides satisfactory results. Further, throughout the proceeding, the Joint Utilities have consistently argued against a fixed charge that differentiates fixed cost components that vary by demand. The Joint Utilities acknowledge that significant cost variation can occur, but the utilities prefer to use an average over all residential customers.[25]

The Joint Utilities proposal for defining fixed costs fails to comport with the requirement that any fixed cost be customer-specific and minimize the regressive impacts resulting from fixed costs that vary by demand. Instead, the Joint Utilities subtract their marginal costs from their revenue requirements, and define the remainder as fixed costs. Using this approach, the amount of fixed costs changes based solely on the difference between total costs and the evolving calculation of marginal costs, with little correlation to individual customer costs.

In contrast, defining fixed costs as customer-specific costs that do not vary with customer usage in kWh or kW, as the Joint Parties do, is consistent with the characterization of fixed costs in D.15-07-001 and focuses on the cost categories that are directly customer-related, and are not demand-related. Such costs do not need to be differentiated by size, dwelling type, or demand levels, and are consistent with the direction provided in D.15-07-001 that a fixed charge should reflect cost causation principles[26] and minimize the regressive impacts resulting from fixed costs that vary by demand,[27] as well as the directive in Public Utilities

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[25] Joint Utilities Opening Comments at 24-26; Joint Utilities Reply Comments at 14 and 15.

[26] D.15-07-001 FOF at 180.

[27] D.15-07-001 at 190.

Code § 739.9(e)(1) that fixed charges "reasonably reflect an appropriate portion of the different costs of serving small and large customers." This approach would also make a fixed charge easy to implement, accurate, and comprehensible. For these reasons, we find the definition of fixed costs used by the Joint Parties reasonable, and adopt it here. To reiterate, for the purpose of this decision fixed costs are (1) customer-specific; and (2) do not vary with usage in kWh or kW.

Today's decision adopts a narrow definition of fixed costs based on the evidentiary record before us. However, there may be other costs that could be included in a fixed charge without violating the requirements of Public Utilities Code § 739.9. In the future, it may be reasonable to revisit and expand the definition of fixed costs for purposes of collecting a fixed charge. However, at this point, the utilities should focus their efforts on the implementation of residential default time-of-use rates as directed by D.15-07-001. After time-of-use rates are established as the standard rate in all three IOU territories, the IOUs, by joint or individual application, may propose an expanded definition of fixed costs that can be included in a fixed charge.

3.2. Fixed Cost Categories to be Included in a Fixed Charge

Depending on the fixed cost definition proposed, the Joint Utilities and Joint Parties support including different fixed costs categories in calculation of a fixed charge. The Joint Utilities have proposed to include all costs that do not vary with usage in kWh. Specifically, the Joint Utilities would include:

- Marginal customer costs;
- Marginal and non-marginal distribution costs;
- Marginal generation capacity costs;
- Non-marginal generation costs;

- Transmission costs; and
- Public purpose program and other non-bypassable costs.[28]

The Joint Utilities would exclude only marginal energy costs, as these costs are usage-related. In contrast, the Joint Parties would exclude everything except a subset of marginal customer costs consisting of non-capital-related costs.

A significant focus of this section is whether the proposed cost categories meet the adopted definition of fixed costs above. First, we start by defining all of the marginal and non-marginal cost categories discussed in the proceeding, and provide examples. Then, we discuss each category in detail below, focusing on whether or not the cost category is directly attributable and assignable to individual customers.

[28] Joint Utilities Opening Comments at 14, 30, and 31.

TABLE 1: Cost Categories

Cost	Description	Example
Marginal Customer Cost	Forward-looking, customer-specific costs of providing electric service that vary with the number of customers	Costs of meters, service drop, and final line transformer; the cost of sending monthly bills, cost of responding to customer inquiries
Non-Marginal Customer Costs	Customer-related costs that do not vary with small changes in the number of customers served	Cost of meter data processing center, customer billing facility, utility's phone center
Marginal Distribution Costs	Forward-looking distribution costs that vary with aggregate customer demand on distribution facilities in kilowatts	Cost of capacity upgrades to wires, line transformers, and distribution substations
Non-Marginal Distribution Costs	Distribution costs that do not vary with demand in kilowatts	Cost of poles, cost of replacing deteriorated distribution facilities that do not include a capacity upgrade, and historical costs associated with distribution rate base that are recovered in distribution rates
Marginal Generation Capacity Costs	Forward-looking costs of generation capacity that vary with system or local demand in kilowatts	A new combustion turbine generator needed to supply system or local area demand
Non-Marginal Generation Cost	Historical costs associated with generation rate base that do not vary with current or future demand in kilowatts	Historical costs associated with generation rate base that are recovered in generation rates

3.2.1. Marginal Customer Costs

Because the Commission's goal has been to design and set rate structures based on marginal cost[29] and cost-causation principles, among others, a major focus in R.12-06-013 and in this proceeding has been on marginal customer costs. Both the Joint Utilities and Joint Parties include part or all of the marginal customer costs in their proposals.

Marginal customer costs are the sum of revenue cycle services (RCS) costs and new connection costs. RCS costs include costs for account set-up, meter reading, billing and payment, and metering services. New connection costs are composed of two types of costs: the cost associated with the investment required to provide a new customer access to the distribution system, and ongoing costs of maintaining service to a new customer. New connection costs are commonly referred to as TSM costs, as they include the cost of final line transformers, service drops, and meters.[30] New connection costs are necessary in order for a utility to provide service to new customers, but can vary significantly by customer type, size, service voltage, and types of equipment used for access.

Parties mostly agree with including the RCS costs in a fixed charge and that at least a portion of ongoing, non-capital related marginal customer costs could be suitable for inclusion in a residential fixed charge. The Joint Utilities argue that RCS costs should include account setup costs, the cost of uncollectable accounts, and customer O&M costs collected directly from customer for service establishment, field collection, reconnections, returned checks, and advanced

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[29] For customer costs, marginal cost is the cost of providing service to an additional customer.

[30] D.86-08-083 at 8 and D.88-12-085 at 14.

meter opt outs.[31] The Joint Parties propose excluding these categories arguing that (1) account setup costs are associated with new customers only; (2) uncollectibles should be excluded pursuant to Commission direction given in the past; and (3) the customer O&M costs collected in service fees would be double-counted if they were included in a fixed charge. [32]

We agree that RCS costs are generally suitable to be included in a fixed charge. We also agree with the Joint Parties that the cost of uncollectible accounts should be excluded from marginal customer costs pursuant to the Commission's past practice, as stated in D.96-04-050, and on the basis that uncollectible accounts are not a marginal cost for bill-paying customers.[33] We also determine that the customer O&M costs that are directly collected from customers for services should be excluded from the marginal customer costs in order to avoid double-charging. However, we maintain that account set up costs are part of the customer services costs and could be included in a fixed charge calculation. We do not see any reason to exclude costs related to customer services, just because a customer is new.

On the inclusion of capital-related marginal customer costs in calculation of a fixed charge, parties disagree, as discussed below.

Meter Costs: Joint Utilities support including all meter costs in calculation of a fixed charge. Although Joint Parties support excluding all capital costs from a fixed charge, they argue that if any capital cost of TSM equipment is to be included, only the cost of meters should be included in a fixed charge

[31] Joint Utilities Opening Comments at 10.

[32] Joint Parties Alternative Proposal at 13 and 14.

[33] D.96-04-050 at Conclusion of Law 23.

calculation. According to the Joint Parties, the cost of a meter does not vary with usage in kW or kWh, and meters are an integral part of the billing function, which they agree is part of customer service costs. They also consider meters as being dedicated to individual customers, so the costs can be directly assignable to customers.[34] However, the Joint Parties argue that "approximately one-third of these costs (relating to advanced metering infrastructure) should be treated as demand-related and not recovered via a fixed customer charge."[35] The Joint Utilities disagree and argue that the utilities are required by the Commission to install advanced meters for new customers and that these meters are essential for time-of-use metering.[36]

Service Drop Costs: The Joint Utilities support including all service drop costs. According to the Joint Parties, service drops - wires connecting from the final line transformer to the customer's meter – vary by customer load and by residence type, single family vs. multi family. Therefore, the Joint Parties argue, inclusion of service drops would require segmentation of customers by residence type or size.[37] According to the Joint Parties, a single composite cost value set based on average marginal customer costs could not recognize the significant cost differences between serving small and large customers. To capture these differences, the Joint Parties suggest creating different charges for single-family vs. multi-family customers. As a second option, the Joint Parties propose basing capital-related charges for all residential customers on the multi-family charges

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[34] Joint Parties Opening Comments at 14.

[35] Joint Parties Opening Comments at 4.

[36] Joint Utilities Reply Comments at 10.

[37] Joint Parties Opening Comments at 4 and 14.

(for SCE), or the costs of serving the smallest customers (for PG&E and SDG&E).[38] The Consumer Federation of California (CFC) considers a similar approach, where charges would be based on the minimum observed cost for the residential class.[39]

Final Line Transformer Costs: The Joint Utilities support including all final line transformer (FLT) capital costs. The Joint Parties argue that final line transformer costs have a demand-related component and inclusion of these costs would require segmentation of customers by size. Similar to their arguments regarding service drops, both the Joint Parties and CFC argue that using averages to account for FLT capital costs in a fixed charge introduces a price distortion within the residential customer class.[40] The Joint Parties also argue that final line transformers are shared among a variable number of residences, creating major differences in cost-causation within the residential class.[41] According to the Joint Parties, these attributes make final line transformer costs unsuitable for inclusion in a fixed charge for the residential class.[42] However, similar to the service drop costs, CFC argues that "the minimum size of an equipment type (*e.g.,* a final line transformer) deployed at any residential customer location could be used to establish a fixed charge—with the differential equipment cost for more costly equipment locations recovered via volumetric

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38 Joint Parties Opening Comments at 5 and 6.

39 Joint Parties Opening Comments at 6, CFC Reply Comments at 5 and 6, CFC Reply Comments on PD at 2 and 3.

40 Joint Parties Opening Comments at 15; CFC Opening Comments at 11 and Reply Comments at 5 and 6.

41 Joint Parties Opening Comments at 3.

42 Joint Parties Opening Comments at 3.

charges. In this way, the cross-subsidy created by limitations in equipment options would be avoided."[43]

Regarding the capital cost of meters, we concur with the Joint Utilities that capital costs of meters should be included in a fixed charge, based on the characterization of meters provided by the Joint Parties, namely: the cost of a meter does not vary with usage in kW or kWh, meters are an integral part of the billing function (which is part of customer service costs), and meters are dedicated to individual customers, so the costs can be directly assignable to customers. Further, since nearly all residential customers can use the same type of meter, no segmentation of customers would be needed. In addition, we agree with the Joint Utilities that the utilities were required by the Commission to install advanced meters, and that the Joint Parties' argument that "ordinary meters can provide metering services at 60% to 70% of the cost of smart meters"[44] is not a valid basis to exclude a portion of the cost of smart meters.

Regarding service drops and final line transformer costs, as the Joint Parties note, these costs vary significantly among different groups of residential customers. For example, costs vary by customer density, by usage of capacity for final line transformers, and by housing type (single- vs. multi-family housing). While the Commission has previously stated that a fixed charge based on customer-related costs could be an appropriate part of residential rate design,[45] it is clear that service drops and final line transformers have a dual function; they are both necessary to serve new customers (customer-related) but

[43] CFC Reply Comments at 5.

[44] Joint Parties Alternative Proposal at 10.

[45] D.15-07-001 at 190.

also contain demand-related components that vary significantly in costs. Including these demand-related cost components not only raises equity concerns, but also introduces a different set of distortions between small and large customers. As argued by the Joint Parties, one potential option to differentiate these costs is to separate them by single-family and multi-family customers; however, as argued by the Joint Utilities, this differentiation proposal is likely a poor representation of the actual demands that small and large customers impose on the system.[46] However, an alternative approach proposed by CFC is to calculate the fixed costs for these assets by using their minimum observed costs within residential class with the remaining to be treated as demand-related, and recovered volumetrically. While we note the Joint Parties' general opposition to including any FLT and or service drop capital costs as fixed costs, we believe that any cross-subsidy issues would effectively be avoided by using the minimum observed cost values.

Inclusion of service drop and FLT costs using the minimum observed residential cost approach would also be consistent with Public Utilities Code § 739.9(e)(1), which requires that any approved fixed charges reflect the different costs serving small and large customers.[47]

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46 Joint Utilities Reply Comments at 5.

47 The minimum observed cost approach discussed by the CFC and the Joint Parties applies only to service drop and final line transformer costs, and should not be confused with SDG&E's Minimum System approach as described in an Appendix to the Joint Utilities Opening Comments filed January 20, 2017. As described, SDG&E's Minimum System approach includes "distribution demand-related costs associated with primary and secondary lines and transformers."

To ensure that utilities use consistent methodologies to calculate the cost of serving the smallest customers, we direct them to propose a cost development method in their 2018 rate design window proceedings. We encourage utilities to leverage the customer marginal cost studies that they are already conducting in their GRC Phase 2 proceedings. We will further discuss implementation of this approach in Section 3.5

3.2.2. Marginal Distribution Demand Costs

The Joint Utilities support including marginal distribution demand costs in a fixed charge, arguing "it is appropriate to include more than just TSM costs in the costs that are eligible for recovery in a fixed charge. A significant percentage of these [distribution] costs of providing service are fixed, *i.e.*, they do not vary based on a customer's energy use." We note that, in supporting inclusion of marginal distribution costs in a fixed charge, PG&E and SCE have changed positions from their initial showings in this proceeding (which excluded marginal distribution costs from their tables of estimated fixed costs).

The Joint Parties oppose inclusion of marginal distribution demand costs on the basis that these costs vary with usage of capacity (kW); inclusion of capacity-related costs would require segmentation of customers by size; and inclusion in fixed charges would violate the following Rate Design Principles:

2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles;
4. Rates should encourage conservation and energy efficiency;
5. Rates should encourage reduction of both coincident and non-coincident peak demand;

9. Rates should encourage economically efficient decision-making.[48]

It is undisputed that marginal distribution demand costs vary with a customers' usage of capacity in kW. The Joint Utilities have failed to demonstrate how marginal distribution demand costs correlate to the actual costs that individual customers impose on the system irrespective of their usage. Further, because large users cause more distribution costs than small users, the inclusion of marginal distribution demand costs in a fixed charge would require, for reasons of equity, that customers be segmented by size. Therefore, we find that these costs should not be included in a fixed charge at this time.

3.2.3. Non-Marginal Distribution and Customer Costs (Use of EPMC Scalar)

Marginal cost revenue is revenue that would be collected if all the customers were charged at marginal cost. In contrast, utility revenue requirement is typically based on embedded (historical) costs as included in rate base. Because of the gap between authorized revenues and the marginal cost based revenues, utilities typically multiply marginal cost revenue with a scalar, called equal percentage of marginal cost or EPMC scalar, to cover this shortfall. The EPMC scalar denotes the percentage by which the authorized distribution revenue requirement, which includes marginal and non-marginal customer costs, is below or above the marginal cost revenue.[49]

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[48] The 10 rate design principles adopted in D.14-06-029 for residential rates can be found in D.15-07-001 at 27 and 28.

[49] Typically, revenue requirement for distribution exceeds marginal cost, resulting in a distribution EPMC scalar greater than 1.0.

Joint Utilities support the use of EPMC while calculating a fixed charge, saying that because marginal customer costs form an incomplete category of fixed costs, revenues based on marginal customer cost fall short of collecting total costs. Therefore, Joint Utilities argue that marginal customer costs must be adjusted during the revenue allocation process by scaling with an EPMC multiplier.[50] Thus, in addition to the marginal distribution costs (customer and demand-related), the shortfall between the residential marginal distribution costs and the authorized revenue requirement, which is recovered through the EPMC scalar, is also considered as a fixed cost by the Joint Utilities. In support, the Joint Utilities argue: "Applying the EPMC scalar to all marginal cost components has been the standard framework adopted by the Commission and applied to rate design proceedings, *e.g.*, GRC Phase 2 proceedings, to ensure that rates are designed so that utilities recover their authorized revenue requirements."[51] The Joint Utilities add that the use of an EPMC scalar is crucial as it ensures that rates reflect marginal costs and are based on cost causation. The Joint Utilities also argue that applying the scalar will have little effect on conservation incentives because they believe that average rates paid by customers will not change much if a $10 fixed charge is adopted.[52]

The Joint Parties strongly disagree. They argue that the difference between the marginal cost revenues and the total revenue requirement that is recovered by means of an EPMC scalar is not a fixed cost that should be covered by a fixed

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50 Joint Utilities Opening Comments at 6.

51 Joint Utilities Opening Comments at 14.

52 Joint Utilities Opening Comments at 16.

charge, because the difference identified as additional fixed cost will vary as marginal cost varies.[53]

In opposing inclusion of non-marginal distribution and customer costs, the Joint Parties state that because the EPMC scalar allocates non-marginal costs from two distinct marginal cost drivers (customer and demand), inclusion of the EPMC scalar in a fixed charge would distort the rate structure by allocating all non-marginal distribution costs to the customer function.[54] There is no separate EPMC scaling process that includes customer-related costs only, because customer-related distribution costs are not separated from demand-related distribution costs in utility systems of accounts. Therefore, the EPMC scalar is not appropriate for use when calculating customer costs separate from other distribution costs.

We find the Joint Parties argument convincing and determine that an EPMC scalar should not be applied in determining a fixed charge. The amount calculated by the use of an EPMC scalar is subject to variation, and not directly linked to customer-specific fixed costs, as the Joint Parties explained, and therefore, it is not a fixed cost according to the definition of fixed cost we have adopted in this decision. To reiterate, we do not reject the use of EPMC scalar for general revenue allocation purposes, but reject its use in determining fixed charges.

Further, we concur with the Joint Parties that inclusion of the EPMC scalar in a fixed charge could distort the rate structure by attributing all the non-marginal distribution cost to the customer function. While we agree in

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53 Joint Parties Alternative Proposal at 4.

54 Joint Parties Alternative Proposal at 6, 7, and 8.

principle with the Joint Utilities that some portion of distribution costs could be considered fixed costs, we are not persuaded that *all* of the non-marginal distribution costs captured by the EPMC scalar are fixed costs. The EPMC recovers embedded distribution costs which are a mix of demand-related and customer-related costs. Inclusion in fixed charges would be inappropriate and could unfairly penalize small customers. Therefore, we decline to include the distribution EPMC scalar in a fixed charge calculation.

3.2.4. Generation Costs

All parties agree that marginal energy costs are usage related and should be excluded from any fixed charge. The Joint Utilities support inclusion of all other generation costs; specifically marginal generation capacity costs and non-marginal generation costs (the latter via the generation EPMC scalar). In support of the former, the Joint Utilities state that a significant portion of generation capacity costs are fixed: "*i.e.,* they do not vary based on a customer's energy use."[55] As with distribution capacity costs, we note that PG&E and SCE have changed from their initial positions, which excluded generation capacity costs.[56]

Joint Parties oppose inclusion of any generation-related costs in a fixed charge, arguing that inclusion of generation costs in a fixed charge would conflict with State energy policies encouraging alternatives to utility-owned generation.[57]

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[55] Joint Utilities Opening Comments at 30 and 31.

[56] PG&E Exhibit PG&E-02, Volume 2, Appendix F, Table F-1, at F-8 , Filed June 30, 2016; SCE Proposed Methodologies And Calculations For Fixed Costs And Fixed Charges For Workshop Discussion, Appendix A, dated October 6, 2016.

[57] Joint Parties Opening Comments at 20.

In addition, the Joint Parties arguments against inclusion of marginal capacity costs and EPMC scaling for distribution would apply as well to generation.

We concur with the Joint Parties (and with SCE's initial showing) that generation costs have no place in a residential fixed charge. First, all parties agree that marginal energy costs are usage related and should be excluded from fixed charges. Second, marginal generation capacity costs are related to usage in kW, and are therefore not fixed costs. Third, we are persuaded by the Joint Parties argument that inclusion of generation costs in a fixed charge would conflict with State energy policies encouraging alternatives to utility-owned generation. For all these reasons, we decline to include generation costs in a residential fixed charge.

3.2.5. Transmission Costs, Public Purpose Program (PPP) Costs and Other Non-Bypassable Costs

The Joint Utilities propose that all non-bypassable charges should be included in a fixed charge calculation. The Joint Utilities include transmission charge, public purpose program charge, Nuclear Decommissioning Charge, Competition Transition Charge, New System Generation charge, and the Department of Water Resources Bond Charge in this recommendation.[58]

There is scant record in this proceeding on transmission costs; nonetheless, the Joint Utilities include transmission costs in their fixed cost calculations. We note, once again, a change of position by PG&E and SCE, whose initial showings

58 Joint Utilities Opening Comments at 31.

excluded transmission costs.[59] The Joint Parties do not support inclusion of transmission costs.

Transmission rates are FERC-jurisdictional, and are currently recovered from residential customers like other rate components, through a per kWh volumetric rate.[60] Nothing on the record here suggests that FERC would accept recovery of transmission costs in a fixed charge. Given the lack of record on this issue, we do not include transmission charges in a fixed charge calculation at this time.

The Joint Utilities argue for the inclusion of PPP costs, stating "these costs are fixed, set by the CPUC to recover costs of energy efficiency programs and low-income discounts and generally do not vary with a customer's usage."[61] They further argue that for non-bypassable costs "to be truly non-bypassable requires recovery through a fixed charge because costs recovered by a volumetric energy rate can be by-passed by reduction in billed consumption that can occur through reductions in consumption and programs such as the Net Energy Metering Program."[62]

The Joint Parties contend that policy-driven costs, such as the costs included in the public purpose program charge (CARE and energy efficiency) are neither fixed nor variable. The driver for these costs is the state itself, not the

59 PG&E Exhibit PG&E-02, Volume 2, Appendix F, Table F-1, at F-8 , Filed June 30, 2016; SCE Proposed Methodologies And Calculations For Fixed Costs And Fixed Charges For Workshop Discussion, Appendix A, dated October 6, 2016.

60 Joint Parties Opening Comments at 30.

61 Joint Utilities Opening Comments at 37.

62 Joint Utilities Opening Comments at 31.

consumer.[63] The Joint Parties also view these costs as costs incurred for alternatives to building power plants, such as energy efficiency and demand response programs and recommend that small customers not be "penalized because the utility and the Commission are following the loading order instead of building generation."[64] Citing Public Utilities Code § 381(a) and § 327(a)(7), the Joint Parties argue that their position is consistent with the statutory requirements that authorize the recovery of public purpose program costs on volumetric basis only. [65]

Public Utilities Code § 381(a) states the following:

> To ensure that the funding for the programs described in subdivision (b) and Section 382 are not commingled with other revenues, the commission shall require each electrical corporation to identify a separate rate component to collect the revenues used to fund these programs. The rate component shall be a non-bypassable element of the local distribution service and collected on the basis of usage.

Public Utilities Code § 327(a)(7) states the following:

> For electrical corporations and for public utilities that are both electrical corporations and gas corporations, allocate the costs of the CARE program on an equal cents per kilowatt-hour or equal cents per therm basis to all classes of customers that were subject to the surcharge that funded the program on January 1, 2008.

We find the arguments made by the Joint Parties reasonable and agree with their position that non-bypassable costs should not be recovered through a fixed charge. Statutes cited above clearly require recovery of public purpose

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[63] Joint Parties Alternative Proposal at 5.

[64] Joint Parties Reply Comments at 13.

[65] Joint Parties Opening Comments at 21.

program charges on a volumetric basis only. We also find the argument that some of the non-bypassable costs are incurred to provide alternatives to conventional generation, such as energy efficiency, and therefore should be equivalent to generation costs in their treatment, convincing. Some of the other charges such as Nuclear Decommissioning charge or new system generation charge are ultimately generation-related and should not be included in a fixed charge.

3.2.6. Summary: Fixed Cost Categories

In sum, as discussed in Sections 3.1 and 3.2, we find the Joint Utilities' expansive view of fixed costs includes a significant amount of costs that are neither customer-specific nor customer-related; conflicts with the fixed cost definition we adopt here; and conflicts with the cost-causation principle of rate design. Therefore, we find the set of cost categories selected by the Joint Utilities unproductive for the purpose of calculating a fixed charge.

D.15-07-001 concluded that "a well-designed fixed charge representing a portion of the fixed customer-related costs to serve the individual residential customer could be reasonable."[66] D.15-07-001 also clarified that, at a minimum, customer specific or customer related (as opposed to demand-related) costs such as meters, billing services and customer services could be included in calculation of fixed charges.[67]

As envisioned in D.15-07-001, we find that customer-specific costs, which reasonably reflect the level of costs that individual customers impose on the system irrespective of their usage, could form the basis of a fixed charge. Our

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[66] D.15-07-001 at COL 16.

[67] D.15-07-001 at COL 19.

findings for cost category eligibility inclusion in a fixed charge are summarized in Table 2.

TABLE 2: Cost Category Eligibility for Inclusion in a Fixed Charge

Category	Subcategory	Fixed charge
Revenue cycle services costs	O&M, billing, customer inquiry	Include (excluding uncollectibles, O&M costs paid by specific customers)
New customer connection costs (TSM)	Meter	Include
New customer connection costs (TSM)	Service drop	Include using the minimum cost approach Exclude costs above the minimum cost as being demand-related (Such costs should be recovered volumetrically.)
New customer connection costs (TSM)	Final line transformer	Include using the minimum cost approach Exclude costs above the minimum cost as being demand-related (Such costs should be recovered volumetrically.)
Distribution	Marginal capacity costs	Exclude
Distribution	Non-marginal costs	Exclude
Generation	Marginal energy costs	Exclude
Generation	Marginal capacity costs	Exclude
Generation	Non-marginal costs	Exclude
Transmission		Exclude
PPP		Exclude
Other non-bypassable costs		Exclude

3.3. New Customer, Rental, and Adjusted Rental Methods

As discussed in Section 3.2.1, marginal customer costs are comprised of revenue cycle services costs and new customer connection costs. Even though parties might agree on including portions of customer connection costs as a fixed cost component, they do not agree on how to calculate customer connection costs. Two competing methods are proposed by parties: the new customer only (NCO) method and the rental method. There are also two variations on the rental method, adjusted rental methods (ARM 1 and ARM 2), introduced by the Commission's Energy Division. SDG&E and SCE also introduced minimum threshold method and y-intercept model as alternate methods on which the capital costs should be based in their January 20, 2017 Opening Comments. The Joint Parties also proposed a modification to the NCO method.

The Joint Utilities support use of the rental method to estimate the new connection component of marginal customer costs, whereas the Joint Parties support the use of NCO method. As explained by the Joint Utilities, under the rental method approach, capital investments are converted into annualized marginal costs by multiplying capital costs by a rental economic carrying charge (RECC). The goal of this approach is to be able to reflect the market value of the equipment and signal the value that an asset would have in a competitive market. The rental method applies the same marginal cost to existing and new customers. The rental method is based on the TSM connection equipment cost at the margin and does not apply any depreciation or deferred tax adjustment. Because the rental method uniformly applies the costs to add or replace one new hookup across all customers in the rate group, the Joint Utilities argue that it provides a more stable estimate of the marginal customer cost.[68]

The Joint Parties criticize the rental method for overvaluing the capital costs of items for which there are no "rental" markets; they consider these costs to be "sunk" after the first year of installation. The Joint Parties argue that the NCO method is superior to the rental method as "it replicates a ratemaking practice that actually occurs."[69]

In response, the Joint Utilities assert that the NCO method understates the marginal distribution customer costs because it takes the upfront present value of the new customer connection cost (not the annualized cost), multiplies that value by the number of anticipated new customers, and then divides it by the total number of customers in the class. As such, the NCO method attributes no marginal cost to TSM equipment being used by existing customers. More importantly, the Joint Utilities argue that the Rental Method is superior to the NCO method because it provides a more stable estimate of marginal customer costs. Specifically, the Joint Utilities state that because the NCO method suffers from high sensitivity to the new connection rate, a sharp increase, decrease, or even a negative new connection rate will result in volatility that is outside of utility control.

While both methods use the same underlying cost data, the NCO method applies a growth ratio that reflects the proportion of new customers to total customers as the basis for determining marginal customer costs. The Joint Utilities argue that this introduces volatility, can at times result in irrational cost

[68] Joint Utilities Opening Comments at 20.

[69] Joint Parties Alternative Proposal at 11.

values, and results in inefficient price signals to customers considering new connections.[70]

As a remedy, the Joint Parties proposed to substitute a system level growth rate for the rate class specific growth rate to help stabilize the marginal customer cost price signal. As pointed out by the Joint Utilities, the use of a system level growth rate might improve the method; however, if a certain rate group's growth rate is significantly different than the system growth rate, the principle of cost causation would be violated.[71]

At workshops the Energy Division suggested that neither method satisfies the basic symmetry property of a marginal cost and neither method values existing hookup equipment correctly.[72] In order to overcome these deficiencies, Energy Division presented two variations on the rental method: Adjusted Rental Method 1 (ARM 1) and Adjusted Rental Method 2 (ARM 2). These methods adjust incremental costs by the utility's historical rate base or accumulated depreciation amounts. The Joint Utilities do not support the use of these methods, as they claim that both methods underrepresent the cost of TSM equipment with ARM 2 representing an estimated replacement cost new less depreciation value for all customer connections at average age, and ARM 1 representing the rate base.

If forced to choose between the two methods, the Joint Utilities prefer ARM 2 over ARM 1.[73] Joint Utilities argue that the ARM 1 "inappropriately uses

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[70] Joint Utilities Opening Comments at 21.

[71] Joint Utilities Reply Comments at A-7.

[72] Energy Division Staff Proposal at 6.

[73] Joint Utilities Opening Comments at 7.

accounting and tax basis of costs as reflected in rate base in the analysis of marginal cost. ARM 1 diminishes the efficacy of the marginal cost price signal as it exaggerates the effective discount of the carrying cost, by using the accounting basis of costs."[74] As SCE explains, marginal cost analysis should be forward looking and historic changes to accounting or tax treatments for past investments are irrelevant and should be excluded from marginal cost analysis. According to SCE, because ARM 1 uses rate base as a determinant of value of customer connection cost, ARM 1 does not conform to marginal cost analysis norms.[75] Joint Utilities prefer ARM 2, because they argue that if ARM 2 is applied correctly, it represents a proxy of the fair market value for a utility's assets.

On the other side, the Joint Parties strongly prefer the NCO method over both ARM 1 and ARM 2.

In December 20, 2016 supplemental filings, PG&E, SCE, and SDG&E provided comparison tables that showed how much each utility's marginal customer costs vary, per customer per month, calculated by applying these methods.[76] For this calculation utilities used marginal customer cost values from their original fixed cost reports, including all TSM costs. As shown below, the variation based on the method used can be significant.

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[74] Joint Utilities Opening Comments at 21.

[75] SCE Response to November 21, 2016 Ruling at 8 and 9.

[76] Supplement to Fixed Cost Report and Comments on Alternative Methodologies filed by PG&E, SCE, and SDG&E.

TABLE 3: Marginal Customer Costs

	Rental method	NCO method	ARM 1	ARM 2
SDG&E	$20.77	$15.42	$14.34	$18.54
SCE	$12.37	$8.30	$5.44	$9.08
PG&E	$10.73	$4.49	$6.67	$7.10

In addition to the methods described above, SDG&E's minimum threshold method and SCE's y-intercept model were also introduced as alternative methods. These methods use regression analysis to assign a portion of the fixed costs. Joint Parties oppose the use of such methods and briefly explain the problems with minimum system approaches, including the complexity and controversy related to these approaches.[77]

We find that parties have made significant progress in articulating and presenting pros and cons of various methods for calculating capital-related customer costs in this proceeding. We recognize the merits of each method and some of the ways in which these methods can be further improved, as illustrated by the Energy Division's proposal to adjust the rental method and the Joint Parties suggestion to modify the NCO method. We see value in using a uniform method across utilities to maintain consistency; however, given the lack of consensus on this issue, the significant variation of customer costs that may result from each method, and the possible broader implications in General Rate Cases from pre-selecting a method, we will not adopt a single method to calculate capital-related customer costs at this time. We would like parties to continue exploring capital-cost calculation methods towards the goal of

[77] Joint Parties Reply Comments at 17.

developing a more universally applied method. We also direct the utilities to show their range of results applying the methods discussed in this proceeding, namely the rental method, the NCO, the adjusted rental methods, and other alternatives to be developed going forward, if any, when they propose a fixed charge in the future.

3.4. Summary: Costs Eligible for Recovery through a Fixed Charge

D.15-07-001 stated the following on the issue of fixed charges:

> "The evidence provided by parties in this proceeding focused on the fact that there is no agreement on how to identify and calculate fixed costs. The IOUs failed to articulate a clear and consistent method, and other parties asserted that this lack of consistency was a primary reason for not approving any fixed charge."[78]

Although similar disagreements on policy continued in this proceeding, we find that the parties were able to articulate their proposals, and Joint Utilities were able to present a consistent method. However, while the Joint Utilities were able to present a consistent method, with the exception of certain marginal customer costs, we find that the methodology put forward by the Joint Utilities generally failed to demonstrate how their proposed fixed cost categories were directly attributable and assignable to individual customers or to the residential customers as a class. With regards to capital meter costs, as well as minimum observed costs for final line transformers and service drops, we conclude that sufficient evidence and record exists to include this fixed cost component as a

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[78] D.15-07-001 at 190.

fixed charge, should the utilities choose to bring forth a fixed charge proposal before the Commission in the future.

In sum, a fixed charge should include only a portion of revenue cycle services costs and all meter capital costs and portions of service drop and final line transformer costs, as set forth in Table 2. Fixed charges cannot cover any costs that vary with demand and must exclude transmission charges and all non-bypassable charges such as public purpose program charges. The EPMC scalar will not be applied when calculating fixed costs for purposes of setting a fixed charge.

We anticipate that fixed charges as calculated by the directives given in this decision will ensure that all customers, including those customers with low or no levels of usage as well as community choice aggregator customers and net energy metering customers, contribute a modest amount towards the fixed costs that utilities incur for serving those customers. In D.15-07-001, the Commission found that, although a fixed charge would not encourage additional conservation, the impact is likely to be small.[79] Given the modest amount of fixed charges that could occur through the fixed cost categories identified by this decision, this outcome is expected here as well; however, final bill impacts of any proposed fixed charges will be reviewed by the Commission in the relevant proceeding, in the event a utility decides to propose a fixed charge.

The Joint Utilities illustrated the forecast bill impacts due to a hypothetical $10 fixed charge for non-CARE customers and $5 fixed charge for CARE customers, using the forecast 2019 two-tiered rate structure with the Super-User

79 D.15-07-001 at 214.

Electric (SUE) surcharge for SCE and PG&E.[80] As shown below, in this scenario, 26 percent of SCE's non-CARE customers and 32 percent of PG&E's non-CARE customers are anticipated to experience increases in their average monthly bills. 27 percent of SCE's CARE customers and 15% of PG&E's CARE customers would also experience increases in their monthly average bills.

TABLE 4: Illustrative Monthly Bill Impacts for PG&E's Customers[81]

	Percentage of Customers	Range of Monthly Bill Impact
Non-CARE Customers	32.4%	$1.49-$4.29
CARE Customers	15.5%	$0.50-$1.62

TABLE 5: Illustrative Monthly Bill Impacts for SCE's Customers[82]

	Percentage of Customers	Range of Monthly Bill Impact
Non-CARE Customers	26.3%	$0.69-$4.40
CARE Customers	26.6%	$0.48-$1.71

In this hypothetical case of a $10 fixed charge, the rest of the customers would receive lower monthly bills. Even though the Joint Utilities refer to these changes as modest bill impacts, it is our expectation that a fixed charge based on the authorized cost categories in this decision is likely to have an even smaller impact on ratepayers' bills.

We take note that determination of a fixed charge method does not imply approval of any specific fixed charges for any of the utilities. AB 327 does not

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80 Joint Utilities Reply Comments at Appendix B.

81 Summarized from Joint Utilities Reply Comments, Appendix B.

82 Summarized from Joint Utilities Reply Comments, Appendix B.

require the Commission to approve any new or expanded fixed charge, and the Commission is not bound by formulaic approaches and can make adjustments if need be. The Commission will continue to evaluate the appropriateness of fixed charges in terms of use and amount on a case-by-case basis. It is not reasonable to decide to impose a fixed charge in a vacuum without taking into consideration all the factors that are reviewed in a rate design proceeding.

Following the implementation of default time-of-use rates, any cost proposed for inclusion in a fixed charge must not vary with demand, usage, or generation, and must not include transmission costs or public purpose program costs.

We also do not adopt the minimum bill proposal of the Joint Parties. The minimum bill approach was suggested as an alternative in Public Utilities Code § 739.9(h), but is not within the scope of this proceeding.

3.5. Implementing a Fixed Charge

Our findings limit the cost components eligible at this time for fixed charge recovery to a subset of marginal customer costs, namely certain ongoing costs; the cost of a meter, and a portion of the costs of the service drop and the final line transformer. Distribution costs upstream of the final line transformer are excluded at this time. As noted before, the Commission may revisit this exclusion in the future.

With this understanding, we direct the utilities, if they wish to implement a fixed charge, to do so based on costs and methodologies that are consistent with their most recent or concurrent GRC Phase 2 marginal customer cost showings. With respect to ongoing costs and meter costs, these costs are already captured in the marginal customer costs and should be included, consistent with the adopted marginal costs, except for the exclusion of certain ongoing costs adopted in this decision.

If the utilities propose to include service drop and FLT costs in their fixed charges, they must develop a methodology to identify the marginal service drop and FLT costs appropriate to serving the smallest customers. We do not specify a methodology here, but rather, use PG&E as an example of how the process could proceed.

PG&E's TSM costs for its marginal customer cost showing are based on an analysis of over 80,000 field-produced customer connection "job" cost estimates gathered over a 3-year period (2013-2015).[83] PG&E states that its customer connection cost database "recognizes the full range of [residential customer connection cost] data, including the valid data on costs at the low and high ends of the cost spectrum."[84]

It is these costs at the low end of the cost spectrum that we wish to capture if service drop and FLT costs are to be included in a fixed charge. This would be consistent with CFC's recommendation that "charges for these items could be based on the minimum observed cost for the residential class."[85]

For PG&E, it should be straightforward to identify those costs, using its marginal customer connection cost database described in its marginal cost testimony in this proceeding.[86] For example, for FLTs, the database could yield a

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[83] PG&E-9 at 7-10 and 7-11 in A.16-06-013.

[84] PG&E-9 at 7-10 and 7-11 in A.16-06-013.

[85] CFC Opening Comments at 11.

[86] PG&E-9 in A.16-06-013.

rank order of per-customer costs,[87] from lowest to highest. The minimum observed cost could be the 10th, or 20th, percentile of the FLT cost distribution, or the average cost for the bottom 10% or 20%. Service drop costs could be analyzed similarly. We direct the utilities (if they wish to include these costs in a fixed charge) to provide a joint proposal in their 2018 rate design window proceedings.

While we endorse PG&E's general approach to gathering customer cost data, and would hope that SCE and SDG&E would at a minimum, validate their TSM equipment cost with data from actual customer connection "jobs," we are open to other approaches, so long as they are reasonably consistent with the "minimum observed cost" approach we adopt here.

Finally, the utilities should not use SDG&E's Minimum System approach which, as described, includes "distribution demand-related costs associated with primary and secondary lines and transformers." Such costs are excluded from the methodology we adopt at this time. For similar reasons, the utilities should not use the "zero-intercept" method or any other statistical method that includes upstream distribution costs.

We reiterate that once the capital costs of meters and minimum service drops and minimum final line transformers are determined following the above guidance, we expect the utilities (if they wish to include these costs in a fixed charge) to show their range of results applying the marginal customer cost methods discussed in this proceeding, namely the rental method, the NCO, the

[87] In addition to the FLT costs, the database contains the number of customers served by each FLT. The per customer cost is the transformer cost divided by the number of customers it serves.

adjusted rental methods, and other alternatives to be developed going forward, if any.

4. Should the Fixed Charges Vary Between Small and Large Customers?

One of the issues under consideration in this proceeding is whether the fixed charges should be differentiated based on customer size and if so, how that characterization should be operationalized. Public Utilities Code § 739.9(e)(1) requires that any fixed charges that may be adopted do "reasonably reflect an appropriate portion of different costs of serving small and large customers." However, Public Utilities Code § 739.9 (e) does not define "small" or "large" customers in the context of fixed charges for residential customers. D.15-07-001 stated that the differentiation most likely refers to customer's usage level or type of dwelling.

Differentiation based on panel size, residence type, single-family versus multi-family, was considered by the parties in this proceeding. However, these approaches were characterized as a poor proxy to costs, hard to understand, impractical or expensive.[88] For example, PG&E noted that it does not have a reliable indicator in its billing system to distinguish between single family and multifamily dwellings, and such a differentiation would be expensive to implement and would add complexity to the implementation of a fixed charge.[89]

The Joint Utilities oppose size differentiation for fixed charges, and argue that it is unfair and unnecessary.[90] They also add that it is important whether the

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[88] Joint Utilities Opening Comments at 25.

[89] PG&E Fixed Cost Report at F-13.

[90] Joint Utilities Reply Comments at 14.

means of differentiation is "accurate, practical, and understandable."[91] The Joint Utilities define the issue as to whether "small" customers with lesser demand or usage have different lower fixed costs of service than "large" customers. The Joint Utilities recommend demand as a more relevant means of differentiating a customer charge than volumetric usage in kWh, and agree that a more reasonable "future" method would be based on actual customer measured demands. Although differentiation of small and large customers might be possible, the Joint Utilities recommend limiting fixed charges differentiation by CARE and non-CARE customers to be preferable, fair under the law, and that more complicated measures not be adopted.[92]

The Joint Parties recommend, if a fixed charge is to be implemented, the use of a single fixed charge for all customers, provided a customer charge was imposed based on operating expenses only.[93] In their view, the differences in the fixed costs among customers arise from differences in capital related costs, especially transformers and service drops, as these differences are attributed to the size of the customer and density of customers.

We agree with the Joint Parties that the differences in the fixed costs among customers arise from differences in capital related costs, especially transformers and service drops, as these differences are attributed to both the size of the customer and density of customers. No party has proposed an adequate method to account for these differences, which supports our decision to limit recovery of fixed costs to those that do not vary based on kW or kWh.

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[91] Joint Utilities Opening Comments at 22.

[92] Joint Utilities Opening Comments at 22.

[93] Joint Parties Opening Comments at 4.

Given that our fixed charge determination is made based on customer costs (meter, minimum service drop and minimum final line transformer costs, and customer services) that are the same for all residential customers and excludes demand-related capital costs, the issue of size differentiation is moot at this time.

5. What is the Proper Timing of Potential New or Increased Fixed Charges in Residential Rates?

In D.15-07-001, the Commission found that a residential fixed charge cannot be implemented until at least one year after the start of default TOU rates.[94] The Joint Utilities recommend that fixed charges be implemented as soon as the proper methodology has been adopted, appropriate customer marketing, education, and outreach (ME&O) efforts have been undertaken and "as soon as practical" after default TOU rates have been established.[95] The utilities have repeatedly expressed their plans to file requests for a fixed charge in their 2018 Rate Design Window applications, to be implemented after the tier collapse and default TOU implementation ordered in D.15-07-001 have occurred. They anticipate that "a fixed charge will not be impacting the overall bill significantly, but reduce the volatility of the volumetric portion of the rate,"[96] pointing out that AB 327 caps the maximum portion of fixed costs that can be included in fixed charges for non-CARE and CARE customers.

Joint Parties recommend that a fixed charge not take effect until: (1) tier flattening and consolidation is complete; (2) any requirement for default TOU rates has been implemented; and (3) residential customers have had sufficient

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[94] D.15-07-001 at 193.

[95] Joint Utilities Opening Comments at 8.

[96] Joint Utilities Opening Comments at 27.

opportunity to acclimate to the new rate structures. They caution that the Commission must recognize the extreme bill impacts for customers using less than 100% of baseline and be careful to avoid bill shocks from a combination of tier consolidation and any fixed charges.[97] Specifically, the Joint Parties recommend postponing implementation of fixed charges until 2020. The Joint Parties argue that (1) a fixed charge accompanied with increases to Tier 1 rates would result in unreasonable bill impacts for low-usage customers; (2) utilities' information and billing systems would be overwhelmed to handle the changes; and (3) because customers will face more challenges such as changes to the TOU periods, there will be need for additional education and outreach efforts.[98]

Center for Accessible Technology agrees with the Joint Parties that timing should take into account bill impacts of a fixed charge combined with other rate changes in progress. Center for Accessible Technology is anticipating significant negative reaction from consumers from implementation of fixed charges. Focusing on the affordability aspect of rates, Center for Accessible Technology argues that there should be at least five years or the duration of the ME&O roadmap until fixed charges are implemented.[99]

In D.15-07-001 the Commission established four conditions to be met prior to further consideration of fixed charges: (1) for each IOU, a GRC Phase 2 decision issues that approves a calculation of fixed charges. To accomplish this, each IOU, in its next GRC Phase 2, must provide sufficient evidence to identify

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[97] Joint Parties Opening Comments at 3.

[98] Joint Parties Opening Comments at 7-11.

[99] Center for Accessible Technology Reply Comments at 10.

and calculate fixed customer costs that are specifically intended to represent marginal customer costs that would be the basis of a fixed charge; (2) a GRC Phase 2 decision issues approving categories of fixed costs for consideration of a future fixed charge; (3) a decision in the IOU's 2018 residential rate design window that approves a new fixed charge request from the utility, (4) default TOU is implemented. The Commission determined that, "Provided that all four conditions have been met, a fixed charge can be implemented with an effective date at least one year after the start of default TOU.[100] The Joint Utilities position conforms to the Commission's determination made in D.15-07-001. However, the Joint Parties bring forth good points regarding affordability and potential implementation issues. These are valid concerns and they should be addressed if and when there is a fixed charge proposal. At that time, utilities should be able to make a showing of the actual bill impact for all customers, including a monitoring plan that tracks customer complaints and disconnections data in relation with the implementation of fixed charges. As we have discussed, the specific dollar amount of a fixed charge cannot be adopted in a vacuum. It needs to be considered as a component of optimal rate design, in which implications of each component should be evaluated. Such an evaluation is not within the scope of the Fixed Charge track of this proceeding. Joint Utilities suggest that any bill impacts that are deemed excessive could be resolved through a reasonable phase-in process. We find merit in exploring this option in the relevant rate design proceedings.

[100] D.15-07-001 at 191, 192, and 193.

The utilities' billing and information systems will need to be well-equipped to be able to make the necessary changes to implement fixed charges. Utilities are expected to make a showing that their billing and information systems are indeed ready for new challenges, when and if, they propose a fixed charge.

The concerns and points made by Joint Parties as stated above can potentially cause delays in implementation of fixed charges, but there is not sufficient evidence presented in this proceeding to prevent the utilities from filing proposals in future rate design proceedings.

For the reasons stated above, in line with the direction provided in D.15-07-001, we maintain the same timeline for the fixed charge proposals, if the utilities choose to bring forth a proposal. Specific bill impacts of a proposed fixed charge will be addressed in the relevant rate design proceeding and the utilities should demonstrate that the utilities' information and billing systems is ready to handle the necessary changes.

6. What are the Marketing, Education, and Outreach Efforts Necessary to Implement Fixed Charges?

Parties have not introduced any new information on the issue of marketing, education, and outreach efforts in this proceeding. The Joint Utilities do not propose to implement new or increased fixed charges for default residential customers until ME&O efforts are conducted in coordination with other rate reform ME&O efforts. The Joint Utilities maintain that their proposed plans that were filed in R.12-06-013 provide detailed and appropriate strategies for educating customers prior to actual implementation of fixed charges. According to Joint Utilities, ME&O Plans are intended to meet and exceed the Commission's guidance on customer acceptance of fixed charges, as discussed in

D.15-07-001.[101] The Joint Utilities add that the review of the rate design reform ME&O Plans and the further collaboration in the ME&O Working Group should be the process for evaluating and integrating fixed charge related ME&O with implementation of Joint Utilities overall rate design reform ME&O Plans.

The Joint Parties did not address this issue in their Alternative Proposal and generally did not provide detailed comments on this item. However, given that a fixed charge will not be implemented until one year after the implementation of default TOU rates, the Joint Parties believe fixed charges will require their own ME&O effort separate from that associated with default TOU rates. The Joint Parties also emphasize the importance of clear and accurate communication to the customer.

Consumer Federation of California notes that based on the past experience with introduction of fixed charges, negative consumer reaction should be anticipated.[102] Consumer Federation of California also supports that ME&O efforts be evaluated and integrated with the ME&O efforts taking place in R.12-06-013.

Given the lack of new information introduced in this track of the proceeding, the Commission will not adopt additional ME&O plans at this time. The Joint Utilities have already committed to including "…specific ME&O plans for customer outreach regarding implementation of their proposed fixed charges, and the plans will be available to the Commission and all interested parties for review prior to implementation of any fixed charge to residential electric

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[101] Joint Utilities Opening Comments at 28 and 29.

[102] Consumer Federation of California Reply Comments at 3.

customers."[103] The Commission expects a showing on the plans for marketing, education, and outreach efforts with respect to the proposed fixed charges and in relation to the TOU rates and in compliance with the directives of D.15-07-001, if and when, a utility files a proposal for a fixed charge.

7. Procedural Matters

The Commission affirms all rulings made by the assigned Commissioner and assigned Administrative Law Judges (ALJs). All motions not previously ruled on in the Fixed Cost track of this proceeding are denied as moot.

8. Categorization and Need for Hearing

The Commission preliminarily categorized this proceeding as ratesetting. (Resolution ALJ 176-3381.) The Commission also made the preliminary determination that hearings are required. However, no evidentiary hearings were held for the Fixed Charge track of this proceeding because no party requested the opportunity for cross examination.

9. Comments on Proposed Decision

The proposed decision of the ALJ in this matter was mailed to the parties in accordance with Pub. Util. Code § 311 and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on August 22, 2017, by the Joint Utilities and Joint Parties. Reply comments were filed on August 28, 2017, by the Joint Utilities, Sierra Club, ORA, SEIA, and CFC. Changes have been made throughout to clarify the decision's language and in response to comments. The most substantial change is to allow the inclusion of some portion of the costs of service drops and final line transformers in a fixed

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[103] Joint Utilities Opening Comments at 29.

charge on the condition that the minimum observed cost approach proposed by the Joint Parties and Consumer Federation of California is applied to compute cost of the service drops and final line transformers. The decision also provides specific direction should the IOUs seek to modify the definition of fixed costs in the future.

In their comments and reply comments, the Joint Utilities claim that the proposed decision ignores past decisions that have included equipment capital costs in determination of marginal customer costs.[104] The Joint Utilities cited past decisions to support their point. The most recent decisions cited by the Joint Parties, D.16-12-024, D.14-12-048, and D.17-08-030, involve approval of settlements and hence are non-precedential. Rule 12.5 states the following:

> "Commission adoption of settlement is binding on all parties to the proceeding in which the settlement is proposed. Unless the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding."

The other decisions cited by the Joint Utilities were issued in 1980s and 1990s. At a time when new rate design issues are at play, the concept of fixed charges needed a fresh look and the Commission was clear in its intention to review the subject in this proceeding rather than relying on the past decisions. Past practices do not deter the Commission from examining the same issues and arrive at possibly different conclusions. Having said that, we underline that this decision does not contradict that TSM equipment costs are customer-specific; rather for service drops and final line transformer costs, the decision finds that a

[104] Joint Utilities Comments on Proposed Decision at 5 and Reply Comments on Proposed Decision at 2.

portion of these costs vary by demand. Even the Joint Utilities agree that there are differences in costs for service drops and final line transformers, which vary by demand.[105] Therefore, we find the Joint Utilities arguments unsupported.

10. Assignment of Proceeding

Carla J. Peterman is the assigned Commissioner and Michelle Cooke and Nilgun Atamturk are the assigned ALJs in this proceeding.

Findings of Fact

1. Public Utilities Code § 739.9(e) provides the Commission with statutory authority to approve "new, or expand existing, fixed charges for the purpose of collecting a reasonable portion of the fixed costs of providing electric service to residential customers, " but it does not require the Commission to approve any new or expanded fixed charge.

2. Public Utilities Code § 739.9(a) describes a fixed charge as "any fixed customer charge, basic service fee, demand charge, or other charge not based upon the volume of electricity consumed." A fixed charge may appear on customers' bills, as a means to collect all, or a portion, of fixed costs.

3. Defining fixed costs as customer-specific costs that do not vary with customer usage in kWh or kW is consistent with the characterization of fixed costs in D.15-07-001.

4. Public Utilities Code § 739.9 does not provide guidance on the cost categories that should be included in a fixed charge.

5. The Joint Utilities approach, as described in pre-January 20, 2017 filings, produces fixed charges in the range of $35-$81 per month per customer. In

[105] Joint Utilities Comments on Proposed Decision at 7.

comments filed on January 20, 2017 and beyond, PG&E and SCE included additional costs which would increase fixed charges beyond the levels they initially proposed. The Joint Parties proposal yields fixed charges in the range of $2.27-$4.70 per month per customer.

6. The expansive view of fixed cost categories that could be recovered through a fixed charge as proposed by the Joint Utilities conflicts with the Commission's adopted rate design principles and would exceed the statutory maximum fixed charge.

7. Marginal customer costs are the sum of revenue cycle services costs and new connection costs.

8. Revenue cycle services costs include costs for account set-up, meter reading, billing and payment, and metering services.

9. New connections costs are composed of costs associated with the investment required to provide access to a new customer and ongoing costs of maintaining service to a new customer. New connection costs include the cost of transformers, service drops, and meters, and they vary by customer type, size, service voltage, and types of equipment used for access.

10. D.96-04-050 excluded the cost of uncollectible accounts from the revenue cycle services costs.

11. Because certain customer O&M costs for service establishment and field collection are directly collected from customers, it is appropriate to exclude such costs from the revenue cycle services costs to avoid double-charging.

12. The cost of a meter does not vary with usage in kW or kWh; meters are an integral part of the billing function, and meters are dedicated to individual customers, so meter costs can be directly assignable to customers.

13. Costs of service drops and final line transformer vary by different types of customers.

14. Marginal demand costs vary with customer usage in capacity in kW and inclusion of such costs in a fixed charge would require segmentation by size.

15. Marginal cost revenue is defined as revenue that would be collected if all the customers were charged at marginal cost. In contrast, utility revenue requirement is typically based on embedded (historical) costs that are included in distribution rate base. Because of the gap between authorized revenues and the marginal cost based revenues, utilities typically multiply marginal costs revenue with a scalar, equal percentage of marginal cost, to cover this shortfall.

16. The amount of costs accounted for using the equal percentage of marginal costs scalar is subject to variation and not directly linked to customer-specific fixed costs.

17. Marginal energy costs are usage related and marginal generation capacity costs are related to kW usage.

18. For residential customers, transmission charge is a volumetric FERC-jurisdictional charge.

19. Public purpose program charge, Nuclear Decommissioning charge, Competition Transition charge, New System Generation charge, and the Department of Water Resources bond charge constitute the non-bypassable costs.

20. Public Utilities Code § 381(a) and § 327(a)(7) require recovery of public purpose program charges on a volumetric basis only.

21. Parties strongly disagree on which methodology is appropriate to calculate customer connection costs.

22. Demand-related costs may differ among small and large customers.

23. Differentiation of costs based on factors such as panel size and residence type were considered in this proceeding, but are a weak proxy for actual costs, hard for the customer to understand, or impractical or expensive to implement.

24. Unlike demand-related costs, ongoing customer costs are the same for each residential customer.

25. D.15-07-001 established four conditions to be met before a fixed charge can be implemented: (1) for each IOU, a GRC Phase 2 decision issues that approves a calculation of fixed charges. To accomplish this, each IOU, in its next GRC Phase 2, must provide sufficient evidence to identify and calculate fixed customer costs that are specifically intended to represent marginal customer costs that would be the basis of a fixed charge; (2) a GRC Phase 2 decision issues approving categories of fixed costs for consideration of a future fixed charge; (3) a decision in the IOU's 2018 residential rate design window that approves a new fixed charge request from the utility, (4) default TOU is implemented.

26. No new information was introduced with regard to marketing, education, and outreach efforts to implement fixed charges.

Conclusions of Law

1. Consistent with the statutory definition of a fixed charge in Public Utilities Code § 739.9, a fixed charge should be defined as a constant fee or charge that the residential ratepayer is required to pay on a monthly basis, regardless of the ratepayer's usage in kWh or usage in kW.

2. Because an expansive view of fixed costs does not accurately represent customer-related costs and conflicts with the rate design principles established in D.14-06-029, the cost categories selected by the Joint Utilities are unproductive for the purpose of calculating a fixed charge.

3. Identifying cost categories that are directly customer-related and do not need to be differentiated by size, dwelling type, or demand levels should allow the Commission to consider easy to implement, accurate, and comprehensible fixed charges.

4. Because revenue cycle services costs are directly customer-related, do not need to be differentiated by size, dwelling type, or demand levels, and parties mostly agree with including them, they are suitable to be included in a fixed charge, with the exception of uncollectibles and certain costs charged to specific customers.

5. All meter costs should be included in a fixed charge calculation because the cost of a meter does not vary with usage in kW or kWh, meters are an integral part of the billing function, and meter costs can be directly assignable to customers.

6. Because they are partly demand-related, the full costs of service drops and final transformers cannot be included in calculation of a fixed charge. The cost of serving the smallest customers can be used to identify the customer-related portion of the costs of service drops and final line transformers.

7. Because marginal demand costs vary with customer usage in capacity in kW and require segmentation by size, marginal demand costs cannot be included in calculation of a fixed charge.

8. Because the amount of costs calculated by the equal percentage of marginal cost is subject to variation and not directly linked to customer-specific fixed costs, they are not appropriately included in calculation of a fixed charge.

9. Because marginal energy and generation capacity costs are related to usage in kWh or kW, they cannot be appropriately included in a fixed charge.

10. Because there is scant record in this proceeding on transmission costs, transmission costs are FERC-jurisdictional, and are currently recovered through a per kWh volumetric rate, we find that they are not suitable to be included in a fixed charge calculation.

11. Non-bypassable charges should not be included in a fixed charge calculation.

12. Given the lack of consensus on how to calculate capital-related customer costs and the significant variation of customer costs that may result from each method, we should not adopt a single method at this time.

13. Making a determination on the use of a minimum bill or a method to calculate a minimum bill is outside the scope of this proceeding.

14. A fixed charge that includes only those customer costs that are the same for each residential customer is fair and reasonable.

15. The need to differentiate between customer sizes is moot because the fixed charge calculation adopted in this decision includes only those customer costs that are the same for each residential customer.

16. Based on the evidence presented in this proceeding, it is appropriate to maintain the timeline established in D.15-07-001 for proposing and implementing potential fixed charges.

17. Utilities who propose a fixed charge in their rate design window proceeding should make a showing for their marketing, education, and outreach plans with respect to the proposed fixed charges.

O R D E R

IT IS ORDERED that:

1. If Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE) and San Diego Gas & Electric Company(SDG&E) propose a fixed charge in the future, they may include only the following categories of fixed costs: Ongoing marginal customer costs (excluding uncollectibles and customer operations and maintenance costs collected directly from the customer), and all meter costs. The minimum observed costs of the service drop and final line transformer may also be included provided that the method for calculating these costs has been approved by a vote of the Commission. Regarding the meter, minimum service drop and minimum final line transformer costs, PG&E, SCE and SDG&E must show in their 2018 Rate Design Window proceedings their range of results applying the rental method, the new customer only method, the adjusted rental methods, and other alternatives that may be developed, bill impact analyses for each method, as well as a monitoring plan that tracks customer complaints and disconnections data in relation with the implementation of fixed charges.

2. If Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company plan to propose a fixed charge in the future and include a portion of the costs of the service drop and final line transformers in that fixed charge, they must present their minimum observed cost proposals in their 2018 Rate Design Window proceedings and request approval of the method the utility will use to determine the minimum observed cost of the service drop and final line transformer.

3. Prior to implementation of a fixed charge, all four conditions established in Decision 15-07-001 must have been met. The effective date of a fixed charge must be at least one year after implementation of default time-of-use rates.

4. If Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company propose fixed charges in the future, they must demonstrate the adequacy of their marketing, education, and outreach plans with respect to the fixed charge proposals in the respective rate design proceedings.

5. Application 16-06-013 remains open.

This order is effective today.

Dated September 28, 2017, at Chula Vista, California.

MICHAEL PICKER
President
CARLA J. PETERMAN
LIANE M. RANDOLPH
MARTHA GUZMAN ACEVES
CLIFFORD RECHTSCHAFFEN
Commissioners